U.S. DEPARTMENT OF ENERGY | Energy Efficiency & Renewable Energy

FEDERAL ENERGY MANAGEMENT PROGRAM

Mid-Atlantic Energy Markets

An Annual Update on Key Issues and Programs for Federal Sites in the Mid-Atlantic United States

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FEMP Federal Energy Management Program

Energy Efficiency Incentive Programs Sprouting Across Region

Traditionally, the Mid-Atlantic states have lagged behind New York and New England in terms of energy efficiency incentive programs, with New Jersey representing the lone exception. In the past year and a half, however, substantial ratepayer-funded energy efficiency programs have emerged in four Mid-Atlantic states and Washington, DC. State legislators and regulatory commissions have adopted policies that drive these changes; traditional distribution utilities (except in Delaware, where a "sustainable energy utility" was created) are in charge of designing, administering, and implementing the programs. Federal energy and facility managers with sites in these areas should educate themselves in order to best take advantage of these new opportunities to leverage their energy projects. To that end, a brief profile of the developments – and more specifically, the resulting programs – is provided for each state.

Pennsylvania

Pennsylvania has taken perhaps the most aggressive steps, going from "0 to 60" in terms of what is available from utilities. The instigator was Act 129, signed by Governor Rendell in October, 2008. The law set energy and demand reduction targets for electric utilities with 100,000 customers or more, imposed significant penalties for failure to achieve the targets, and allowed the utilities to use (and recover) up to 2% of their electric revenues to implement the programs.

While there are some variations across utilities, the commercial and industrial (C&I) customer package from each provides a substantial set of prescriptive incentives (e.g., dollars per lamp or ton of cooling capacity) that generally constitute about half the cost of making the efficiency upgrade (i.e., half the difference between a standard and high-efficiency model). Covered equipment ranges from Energy Star CFLs to high-efficiency electric chillers. Where equipment is not covered, or where "whole-building" savings are achieved through a combination of measures (or through re-commissioning), custom incentives – which remunerate customers based on their project's first year of savings (at a cents per kWh rate) – are offered. Generally, custom savings need to be documented based on accepted measurement and verification procedures detailed by the program rules.

Because of the demand (kW) target set by Act 129 – which states that the average of each utility's top 100 hours of demand in their 2012-13 fiscal year must be reduced 4.5% (weather adjusted) from the level in 2007-08 – Pennsylvania utilities are also offering load management and demand response programs. While these DR programs have not been as fully formulated as the energy efficiency offerings, they will in most cases run the gamut from permanent load reduction incentives (for measures such as thermal energy storage and gas cooling) to direct load control (where the utility has the ability to cycle or turn off air conditioning units) to conventional demand response programs.

Customers seeking to take advantage of the Pennsylvania incentives can either apply to receive them directly or assign them to a contractor, such as an ESCO or curtailment service provider. While there are exceptions for prescriptive incentives, a general recommendation is to assume that a pre-application to the utility, usually short and simple, is necessary for remuneration.

Delaware

The Delaware Sustainable Energy Utility (SEU) was authorized by state legislation in 2007, and came into being in 2009. Funding is coming from special purpose bonds, a system benefits charge to Delaware ratepayers, ARRA ("stimulus") funding, and proceeds from Delaware's portion of the Regional Greenhouse Gas Initiative's (RGGI) carbon auctions (for more on RGGI, see the February, 2009 edition of this newsletter).

The idea of the SEU, mimicking similar structures in Vermont and Oregon, is to create an independent entity whose sole responsibility is promoting conservation and renewables. The proponents of this administrative model believe that the SEU will offer a single set of programs across customers in the state, and thus take advantage of economies of scale and synergies between energy efficiency and renewables (in areas ranging from program design to marketing to implementation).

The SEU offers a set of prescriptive rebates and a custom incentive program for commercial/industrial consumers under its “Efficiency Plus” program. The prescriptive program offers fixed remuneration levels for various retrofits, including lighting, ENERGY STAR® appliances and commercial cooking equipment, HVAC, water heating, motors and drives, and renewables. The SEU also provides up to $2,000 in co-funding for energy audits, as long as at least one recommended measure is implemented. An audit is necessary in order to receive any of the custom incentives.

There is currently a $20,000 per participant cap on the incentive that can be received, and all incentives need to be pre-approved.

Washington, DC

The DC City Council in 2008 authorized the creation of a sustainable energy utility, such as the one just formed in Delaware. However, the interim plan was to have energy efficiency programs and incentives provided by the city’s electric distribution utility, PEPCO. This began in 2009 and was expected to continue for three years. However, because of a funding shortfall in the DC city government, ratepayer monies earmarked for these programs have been pulled back and the programs discontinued for FY 2011 (which begins on October 1, 2010, like the federal FY).

Prior to the pullback, PEPCO had been offering a broad range of prescriptive rebates for most standard C&I energy efficiency retrofits, as well as a generous program to incentivize commissioning, both in existing buildings and new construction. PEPCO also offered a custom incentive program that covered any electricity-saving measures beyond the prescriptive and commissioning programs. Customers are advised to consult the PEPCO website (www.pepco.com/business) during FY ’11 to stay abreast of any potential developments with this situation.

Maryland

The primary policy driver in Maryland was the EmPOWER Maryland legislation, passed and signed into law in 2008, which set a “15 by ‘15” (i.e., 15% savings by 2015) electricity savings target for the state and mandated that Maryland’s distribution utilities create programs to help achieve this goal.

At this point, all of the major investor-owned utilities (BG&E, PEPCO, Delmarva Power, and Allegheny Power), as well as the Southern Maryland Electric Cooperative (SMECO) have launched C&I programs. Utilities offer a fairly comprehensive set of prescriptive rebates, which aim to cover roughly half of the incremental cost to upgrade to high-efficiency equipment (or about 75% in new construction). In addition, each utility is offering custom energy efficiency programs, where “whole-building” savings are rewarded. BG&E, PEPCO, and Delmarva also offer re-/retro-commissioning incentives; BG&E will cover up to 75% of the cost of a re-commissioning (up to $15,000), while PEPCO and Delmarva offer 50% and up to $30,000. While Allegheny and SMECO do not currently offer specific commissioning programs, savings from commissioning projects would be eligible for incentives under their custom programs.

Virginia

Virginia's first foray into energy efficiency incentives is limited to its largest electric distribution utility, Dominion Virginia Power. The two C&I programs Dominion sponsors are called HVAC Rewards and Lighting Rewards. Both offer prescriptive per-unit remuneration for energy-efficient installations, which range fairly widely within the covered categories, from screw-in CFLs ($1.50) to large water-cooled chillers ($17/ton for units with .46 kW/ton or lower rated (consumption). Applications do not need pre-approval but must be submitted no more than 90 days after the installation is completed. Incentives over $10,000 require an inspection by Dominion.

In conclusion, these four Mid-Atlantic states – Pennsylvania, Delaware, Maryland, and Virginia – are all offering significant incentive programs for energy efficiency projects where virtually none existed just eighteen months ago. Moreover, in Pennsylvania and Maryland these incentives are quite comprehensive and offered statewide. Federal customers are encouraged to take advantage of these programs in the Mid-Atlantic region to leverage their energy projects. Eligible projects include those conducted from appropriated funds as well as alternatively financed energy efficiency projects (such as ESPCs, UESCs, and even PPAs, for renewables incentives). For specific links to actual program websites, either visit your utility's site directly or consult FEMP's energy incentives website, at www1.eere.energy.gov/femp/financing/energyincentiveprograms.html.

New Money: EE Projects Can Now Participate in PJM Capacity Market

Funding opportunities to help leverage energy projects in the Mid-Atlantic region continue to expand. The PJM Capacity market's inclusion of Energy Efficiency (EE) resources is another major example of this trend and has been used by utilities and state PUCs to expand demand-side management. In PJM, EE Resources installed after June 2008 and providing at least 100 kilowatts (kW) in electricity savings can be offered as capacity for up to four consecutive years, beginning in PJM's 2012/2013 Delivery Year.

PJM has had a forward capacity market since 2007. PJM runs the capacity market, which they refer to as the Reliability Pricing Model, to ensure they will have enough electric capacity to meet the forecasted load several years out. Because traditional capacity can take a long time to come on-line, PJM conducts capacity auctions three years in advance of a given Delivery Year, which runs from June 1st to May 31st, allowing new capacity sufficient time to become available. Through the auctions, PJM takes supply offers from generators, demand response programs, and now EE projects, and accepts the lowest cost offers that combine to meet the forecasted demand. Accepted offers of supply from these sources are paid the auction clearing price, the highest accepted offer in the relevant location.

How to Participate

In order to participate *directly* in capacity auctions, a federal facility needs to be a member of PJM. Being a member involves meeting the definition of end-use customer, sharing costs of PJM's operations, and complying with orders dealing with emergency conditions, among other responsibilities. It is seldom worthwhile for customers to become members of PJM, unless their energy consumption is very large such as with a steel mill. For most consumers it is easier and more straightforward to participate in this and other PJM programs through an existing PJM member, such as their utility, an ESCO, or an independent curtailment service provider (CSP).

Because energy efficiency resources are a new entrant into the PJM markets, federal facility managers should be sure to raise this issue with the contractors conducting their financed (ESPC and UESC) projects. Federal facilities pursuing appropriations-funded projects, such as those under the DoD's ECIP initiative, can enlist a CSP, such as those typically involved with PJM through demand response programs, to enroll their EE project's savings into the auctions.
Payments from the capacity program generally go to the CSP, ESCO, or utility directly participating in the auctions. Consequently, customers that work with ESCOs and others should be aware that EE projects may be eligible for capacity auctions and carefully review their contracts to ensure they are being compensated appropriately for the value they provide.

Eligible EE Resources

To qualify as an EE Resource for the PJM capacity market, an efficiency project must exceed building codes or appliance standards at the time of installation. The amount of capacity that can be offered by an EE Resource is known as the Nominated EE Value. The Nominated EE Value is calculated as the expected average demand reduction between the hours of 15:00 and 18:00 Eastern Time from June 1 to August 31 of the Delivery Year (not including weekends or holidays). The minimum Nominated EE Value that can be offered is 100 kW. Examples of eligible efficiency projects include efficient lighting and air conditioning systems, as well as building insulation and permanent load shifts. The project must be fully installed by the start of the relevant PJM Delivery Year and be operational for the entire year to be eligible.

Dispatchable projects, where customers can change consumption levels based on market prices or signals from system operators, are not eligible as EE Resources; dispatchable projects are usually eligible to participate in PJM's capacity market as "load management" resources, however. An EE Resource can offer capacity and be paid in the capacity market for the four consecutive Delivery Years after it has been installed. This means an EE project installed just before summer of 2009 would be eligible to provide capacity for Delivery Year 2012/2013 (the first year of eligibility for EE resources). An EE project installed just before summer 2012 would be eligible to provide capacity for Delivery Years 2012/2013 through 2015/2016.

Mechanics of PJM Capacity Market

Eligible EE Resources may participate in the Reliability Pricing Model capacity markets run by PJM, known as the Base Residual Auction and the Incremental Auction. The Base Residual Auction is PJM's main capacity auction. It is run annually in May to obtain enough capacity to cover the PJM forecasted load for the Delivery Year three years out. For example, the Base Residual Auction for the 2012/2013 Delivery Year was held in May 2009.

The Base Residual Auction is a locational single-clearing price auction, which means the highest accepted offer price is paid to each accepted offer in a given location. Suppliers and loads are divided into geographic zones called Locational Deliverability Areas (LDAs) – see Figure 1. These areas are defined by PJM to ensure that the capacity secured through the auctions is deliverable to the load via the transmission system. Because providing capacity in certain congested areas may be more expensive than in others, PJM allows for different clearing prices in the various LDAs. Since EE Resources often do not face the siting restrictions of their traditional generation counterparts in congested or highly populated areas, the LDAs provide a good opportunity for EE Resources to receive prices that recognize the higher locational value of their capacity.

The map below shows locational prices for capacity from the 2012/2013 Base Residual Auction, held on May 4, 2009. Prices are in dollars per megawatt per day, and are paid for the entire Delivery Year. For example, an accepted offer of 2,000 kW of capacity in the PSN region would be paid $0.185 dollars each day of the Delivery Year for each kW; the total payment over the year would be $135,050.

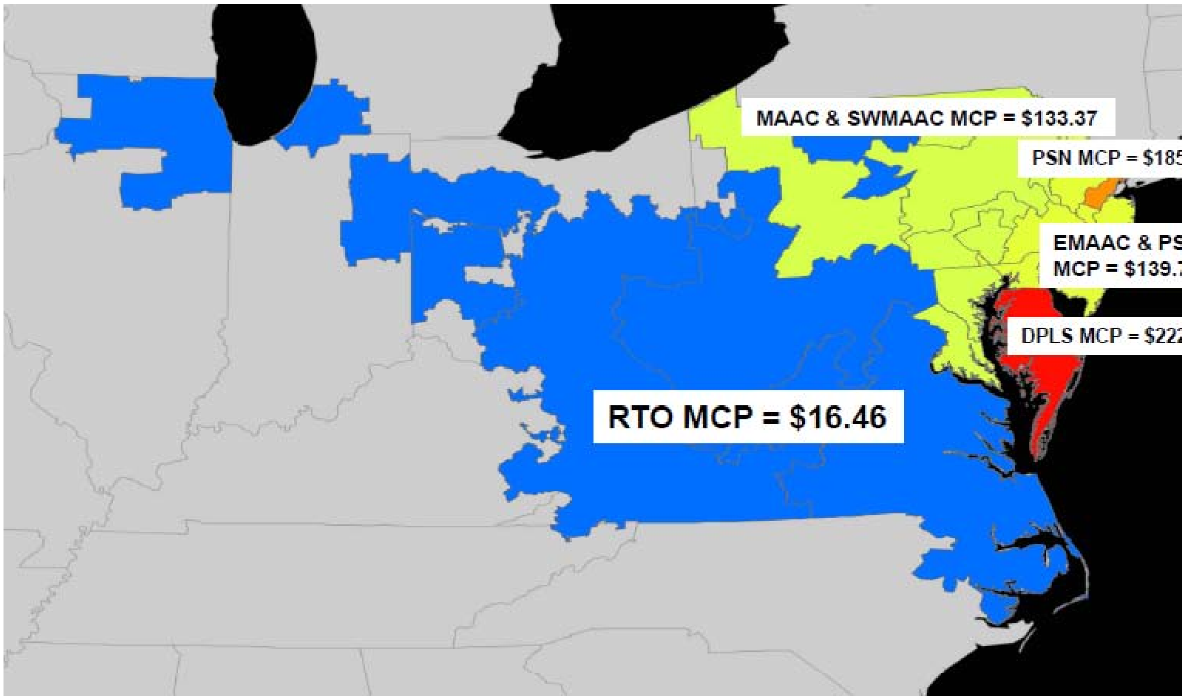

Figure 1. PJM Locational Based Residual Auction Results Delivery Year 2012/2013
Source: PJM website (www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/2012-2013-bra-clearing-price-map.ashx)

Incremental Auctions, also locational single-clearing price auctions, are held in the time between the Base Residual Auction and the start of the Delivery Year to cover any changes to capacity resources or load forecasts that arise. For EE Resources, the Incremental Auctions present an opportunity to offer any additional electricity savings (or to cover a reduction in committed available electricity savings) due to changes in the project. Three Incremental Auctions are held for each Delivery Year, at 23, 13, and three months before the start of the Delivery Year, respectively. Payments for the Base Residual and Incremental Auctions are settled monthly during the Delivery Year.

Once the offerer of an EE Resource has committed capacity through the auctions, it is expected to deliver an amount of capacity based on its Nominated EE Value (the energy reduction in summer peak hours, as described above), for the entire Delivery Year. On a daily basis, PJM monitors compliance, and if a Commitment Shortage is found, the EE Resource offerer is assessed a Daily Capacity Resource Deficiency Charge. The Deficiency Charge is based on the price received in the capacity auction plus either twenty percent of that price or $20/MW-day, whichever is higher. These charges are subtracted from the monthly capacity payments for the EE Resources. Customers working with ESCOs and other third parties should check their contracts for how their service provider manages possible shortages.

M&V Reporting Requirements

Payments for capacity are intended to ensure enough power will be available when needed. Therefore, measuring the savings from an EE Resource is a critically important part of this program. In order to

participate in PJM's capacity auctions, EE Resource offerers must produce and file a series of Measurement and Verification (M&V) reports.
The Initial M&V Plan is produced before a project is installed. It includes general project information, such as company name, project goals, EE technologies to be used, and anticipated Nominated EE Value (as defined above), as well as M&V information, including how savings will be measured and baseline and post-installation assumptions. An Initial M&V Plan is due at least 30 days before the auction (Base Residual or Incremental) in which the Nominated EE Value is initially offered as capacity. An Updated M&V Plan is required if any changes are made to the Initial M&V Plan, such as changes to project schedule or Nominated EE Value.

Once an EE Resource has been installed, an Initial Post-Installation M&V Report is required. The Initial Post-Installation M&V Report contains information about what equipment and systems were actually installed, and ensures that they are operating correctly and able to produce the Nominated EE Value savings. If any changes are made to this Initial Post-Installation M&V Report, an Updated Post-Installation M&V Report is necessary. Submission of the Initial or Updated Post-Installation M&V Report is required 15 business days prior to the beginning of the Delivery Year in which the EE Resource is providing capacity.

At any time after installation of a project, PJM or an independent third-party contractor may perform a Post-Installation M&V Audit. If discrepancies are found between the self-reported Nominated EE Value and actual savings observed during the audit, a new Nominated EE Value is registered and used in the upcoming Delivery Year. If the Delivery Year has already begun, the new Nominated EE Value will be used in the compliance process.

This article presents the basics of how EE Resources may participate in the PJM capacity markets. More information can be found on the PJM website, www.pjm.com, under Reliability Pricing Model; in "PJM Manual 18: PJM Capacity Market" (Revision 8, January 2010) and "PJM Manual 18b: Energy Efficiency Measurement & Verification" (Revision 0, April 2009); or by contacting the PJM Reliability Pricing Model team at rpm_hotline@pjm.com, by phone at 610-666-8980, or toll free at 866-400-8980.

Expose Yourself: Electric Market Rewards May Outweigh Risks

Fixed, flat priced electricity – for instance, at 6¢ or 8¢ per kilowatthour (kWh) – has some attractive features. First of all, it's intelligible, which is a far cry from many rates. Second, a fixed, flat price relieves facility managers from concerning themselves with time-of-use and demand charges, and thus allows them to approach energy management opportunities with a straightforward understanding of their implications. Last, flat-priced electricity permits a great deal of budget certainty: if you are reasonably confident of your facility's consumption, you can develop a decent estimate of your costs for a given month or year.

But these benefits come at a cost. A few studies looking at electricity pricing in areas of the U.S. with wholesale markets – such as those run by independent system operators/regional transmission organizations (ISO/RTOs) like PJM and the New York or New England ISOs – have estimated that fixed, flat-priced electricity costs about 5-10% more, on average, than electricity purchased on the hourly market under a "real time pricing" tariff.[1]

The reason for this premium is that when a facility contracts for fixed, flat-priced electricity, another party is assuming the true market price risk. Whether this is the power marketer from whom the facility is buying the commodity or another entity up the chain, the fact remains that wholesale electricity energy markets have volatility and someone is assuming the risk. Prices tend to be higher during the day when demand is greater and lower at night when demand is limited; seasonally, prices are generally highest when the pull on the grid is greatest, either due to summer heat (in "summer-peaking" areas) or winter cold (in regions where demand peaks in the winter). Price spikes can be very pronounced, with electricity selling for over $1,000/MWh ($1.00/kWh) in some strained conditions in some markets and reaching zero or nearly so when demand is considerably muted (usually at night, especially in mild "shoulder" seasons).

A 5-10% premium may not seem an unreasonable price to pay for the security of knowing one's commodity rate and likely costs. However, if this premium is applied to the annual electricity procurements of a large federal site with a $10 million yearly electric bill, the cost for this security represents between half a million and a million dollars. And since federal facilities, *en masse*, represent a diversified portfolio of procurement in any given region of the country – sourcing large amounts of electricity over a long term – the argument for paying to protect against occasional price spikes becomes even less defensible. Ken Shutika of GSA's Energy Division notes that

> The federal government would appear to be in a unique position in that it should have the financial resources to self-insure itself by taking on hourly priced risks (modest risks in the short term and no risk at all long-term) rather than pay to fix the price in the future (essentially buying insurance to fix the price for budgetary purposes). The government typically does not buy insurance and instead self-insures itself against loss. One could make an argument that fixing electricity prices is buying insurance. That said, additional budgetary flexibility may be required to move away from fixing prices.

Furthermore, this modest increment of 5-10% assumes that no actions are taken to actually respond to changes in price. If facilities have some capacity to adjust their usage in reaction to price spikes, the savings can be considerably greater. This responsiveness can also provide a measure of security – a hedge – against the occasional price spikes, insulating customers from the inherent volatility of electricity markets.

So what's a Mid-Atlantic federal ratepayer to do? There are numerous degrees to which customers can expose themselves more to the wholesale markets and take advantage of the potential to respond to prices. First of all, while only about 15 states have retail competition ("electric choice"), even customers in non-"restructured" states – i.e., those who must buy generation from their electric distribution utility – often have dynamic pricing options. And most areas of the Mid-Atlantic, including New York, Pennsylvania, New Jersey, Maryland, Delaware, and Washington, DC, are among the deregulated states where electric choice is the norm for large customers.

Customers in these "retail choice" states generally have two broad options. They can continue to purchase electric generation (i.e., commodity energy) from their electric distribution utility, which will usually offer a default tariff for large customers that is based on the real-time or day-ahead hourly market. Alternatively, they can select a 3rd-party provider of electricity. In the latter case, federal customers can choose among various products, ranging from real-time pricing (RTP) to "block-and-swing" products

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[1] This effect is more pronounced in markets that do not have separate capacity markets, which these three ISO/RTOs do. Separate capacity markets have the effect of isolating the substantial cost of erecting new "peaker" plants from the hourly wholesale electricity markets, and thus mute volatility and price spikes somewhat in these markets.

(where a portion of the customer's load is purchased at a flat price and any usage above that is assessed at real-time prices) to flat-priced power.

If your site has any ability to respond to prices[2], we recommend that federal customers seriously consider exposing some portion of their load to wholesale markets (via dynamic pricing), or at least participate actively in ISO/RTO or utility-sponsored demand response programs. Probably the best way to do this is through contracts with retail suppliers or tariffs based on hourly pricing in the day-ahead market; this allows the customer to see the pricing it will face a day ahead of time, such that it can plan its load response accordingly. For customers whose default tariff is based on hourly real-time energy market prices, the day-ahead market prices provide some measure of predictability, but it's not perfect – one study revealed about 70-80% correlation between day-ahead and RTP prices.

Another option, for more risk-averse customers, is to obtain flat-priced power but very actively participate in formal demand response programs (as opposed to dynamic pricing). In the PJM footprint, this could mean participating in its forward capacity market (see article on the PJM FCM, below) and/or bidding load reductions into PJM's day-ahead energy market. Both of these activities need to be conducted through a PJM member, such as an independent curtailment service provider (CSP). The Defense Logistics Agency's energy procurement arm (DLA Energy) has established master agreements with over a dozen of these CSPs active in PJM and can assist federal customers in working with them (contact Larry Fratis at DLA: lawrence.fratis@dla.mil, 703-767-8528).

Market Exposure Case Study: Moorhead FOB, Pittsburgh

One example of the benefits of switching to dynamic pricing is GSA's Moorhead Federal Building in Pittsburgh, Pennsylvania. This 785,000 square foot office building purchased its power from a 3rd-party supplier at a fixed, flat price until May 2008, when it started buying most of its electricity through PJM's day-ahead hourly market[3]. In its first two years under dynamic pricing, Moorhead saved almost $235,000, roughly 14.4% of its electricity costs, relative to what it would have spent had it locked into flat-priced power.

The key to Moorhead's success is combining the new electricity procurement scheme with the strategic use of its thermal energy storage (TES) system, 39 tanks (roughly 7,000 ton-hours) of ice storage that were installed in the 1990s. In fact, Moorhead made the switch to the day-ahead pricing after an analysis showed that, given the flat-priced rate the facility was paying, use of the TES system had been providing little to no economic benefit to the facility.[4]

[2] Load response can take the form of a thermal storage system, simple load curtailment schemes (e.g., through controllable dimming ballasts or temperature setback regimens), or on-site generation that can be utilized to hedge against price spikes (most diesel generators in the Mid-Atlantic are restricted to "emergency" demand response – i.e., when there is a brown- or black-out threat – so be sure your permit allows response to "economic" events).

[3] GSA procures between 80% and 95% of Moorhead's expected load in the day-ahead market, with the remainder coming from spot market purchases. While the initial plan had been to pursue a block-and-swing strategy – purchasing some portion of the load at fixed prices – some specific market forces convinced GSA not to buy blocks at the outset. The TES strategy has been implemented by Moorhead so successfully that its hedging capability, along with low prices in the day-ahead market during the past two years (helped by the recession), have served to mute GSA's interest in re-visiting the block pricing.

[4] The slight benefit provided to Moorhead was the likely reduction of the facility's electric "capacity" costs. These charges, billed by PJM to any electricity suppliers in its footprint, are assessed according to customers' power (kW) demand during PJM's five highest hours of summer power draw across its 14-state grid. However, since Moorhead was paying flat electricity prices, the cost to make its ice at night was considerably higher than the normal nighttime market prices.

Under the current scheme, Moorhead uses its chillers during the summer to make ice overnight, when power prices are considerably cheaper, and then discharges (melts) the ice during the day to provide air conditioning. This permits the site to operate during hot summer days using only one of its 600-ton chillers.

Moorhead has three ice-making and -melting schemes, based on the use of a proxy for the likely state of the PJM electricity market. The site receives an e-mail each day from a consulting company that indicates whether the following day is likely to be a mild (green), moderate (silver), or high (gold) electric demand day in PJM. The operations staff responds in one of three ways (see Table 1) in order to minimize electric usage during the peak-setting afternoon hours. The most severe, or gold, days are called roughly 10-12 times per summer. A gold e-mail indicates that this day has a high chance of including one of PJM's five highest demand hours of the year, and thus that the customer's "peak load contribution" may be affected.

The peak load contribution is what is used to determine customers' capacity charges for the following year. Moorhead, like almost all GSA customers receiving 3rd-party electric supply in the PJM footprint, pays its capacity charges as a straight pass-through charge (i.e., the charge is not folded into its kWh rate but is paid separately each month, in order to incentivize and take advantage of, facilities' ability to respond to gold day calls). Consequently, electric load reductions during these days have a double effect for Moorhead: They not only avoid likely high energy prices on the grid, but also help to reduce future capacity charges for the facility.

Table 1. Moorhead strategy for ice making and discharge

Day Type (likely market demand in PJM)	Operational Response	Comment
Green (mild)	On the day before a green day, ice-making should begin no sooner than 21:00 and proceed until no later than 7:00 of the green day. Discharge can be spread across the day, with the ice complementing the operation of the lead chiller.	Goal is to cut edge off load; assumes small price rises during day.
Silver (moderate)	On the day before a silver day, ice-making should begin no sooner than 21:00 and proceed until no later than 7:00 of the silver day. Discharge should begin at 12:00 and proceed until the cooling system is turned off (17:00 or later). If the ice alone can handle the cooling load in the building during this time, no chiller should be used.	Goal is to take advantage of expected moderate price rises in afternoons.
Gold (high)	On the day before a gold day, ice-making should begin no sooner than 21:00 and proceed until no later than 10:00 of the gold day. Discharge should begin at 13:30 and proceed at full melt until the cooling system is turned off (17:00 or later). If the ice alone can handle the cooling load in the building during this time, no chiller should be used. If one of the chillers is required in addition to the ice, it should be loaded as minimally as permissible to still keep the building comfortable.	Goal is to minimize late afternoon load (and reduce PJM capacity charges) with expectation that prices will spike then.

Conclusion

While Moorhead's TES system provides significant flexibility to respond to high demand conditions (and prices) in the market, it is not unique: Many federal facilities, perhaps even most, have the ability to alter their electric loads in response to a market signal. The load reduction capability may come in many potential forms other than TES, such as:

- pre-cooling/load-limiting, where the site is over-cooled somewhat overnight and then run on less cooling (e.g., one chiller instead of two);
- letting the temperature rise one or two degrees in the facility for a short time;
- dimming lights (requires dimmable ballasts);
- shifting the operation of an electricity-intensive experiment or process to lower demand hours; and
- operating self-generation (assuming the air permitting allows it).

While the axiom that those who take the greatest risks stand to reap the greatest rewards is certainly true in electricity procurement – at least given a reasonably long term – those rewards can be achieved more quickly, deeply, and with less risk by end users that have the ability to hedge by dropping load when market prices surge. And given the long-term perspective that most federal facilities can and should adopt in their energy management decisions, electricity market exposure – even its most extreme form, real-time pricing – makes eminent sense.

Agencies interested in additional assistance in accessing public benefit funds or demand response programs in the mid-Atlantic region should contact Phil Coleman (PEColeman@lbl.gov, 610-604-0170) or Chuck Goldman (CAGoldman@lbl.gov, 510-486-4637) with Lawrence Berkeley National Laboratory.

Requests for technical assistance with implementing energy projects at your site can be directed to Tracy Logan (tracy.logan@ee.doe.gov, 202-586-9973) of FEMP.

FEMP continues to closely monitor the energy situation in the mid-Atlantic region through these periodic newsletters. Additional information on the public benefit-funded opportunities available to Federal customers can be found on the FEMP web site at: http://www1.eere.energy.gov/femp/financing/energyincentiveprograms.html.

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